PRODUCTION OF NATURAL GAS AND FLUID FLOW IN TIGHT SAND RESERVOIRS

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2 ABSTRACT

This document reports progress of this research effort in identifying possible relationships and defining dependencies between macroscopic reservoir parameters strongly affected by microscopic flow dynamics and production well performance in tight gas sand reservoirs. Based on a critical review of the available literature, a better understanding of the main weaknesses of the current state of the art of modeling and simulation for tight sand reservoirs has been reached. Progress has been made in the development and implementation of a simple reservoir simulator that is still able to overcome some of the deficiencies detected. The simulator will be used to quantify the impact of microscopic phenomena in the macroscopic behavior of tight sand gas reservoirs. Phenomena such as, Knudsen diffusion, electro-kinetic effects, ordinary diffusion mechanisms and water vaporization are being considered as part of this study. To date, the adequate modeling of gas slippage in porous media has been determined to be of great relevance in order to explain unexpected fluid flow behavior in tight sand reservoirs.

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4 EXECUTIVE SUMMARY

The main goal of this research is to identify possible relationships and define dependencies between macroscopic reservoir parameters strongly affected by microscopic flow dynamics and production well performance in tight gas sand reservoirs. To achieve this goal, the Center for Energy and Technology of the Americas (CETA) is identifying microscopic flow mechanisms that affect fluid flow through a critical review of the literature, and through the development and implementation of simulation and modeling techniques that can be used to explain macroscopic behaviors of tight sand gas reservoirs. Phenomena such as, Knudsen diffusion, electro-kinetic effects, ordinary diffusion mechanisms and water vaporization will be included in this study. Subsequently, CETA will evaluate the impact of reservoir features on fluid flow dynamic behavior. Such features could be fluid properties, reservoir depth, net sand thickness, reservoir permeability, and data from drilling and stimulation processes.

An extensive and critical review of the literature was performed. From the review we detected that there are diverse interpretations and implementations of the commonly termed slippage phenomena into reservoir simulations. Our analysis indicates that they result in widely different predictions of fluid flow in tight sand reservoirs. We developed a 2-D numerical simulation model to test the importance of different phenomena on the predictions of fluid flow. One of the phenomena that had great impact is the slippage and, more specifically, the way it is considered in the macroscopic equations. This clearly led to the conclusion that most commercial reservoir simulators may have severe limitations when used to model fluid flow in tight reservoirs given that certain phenomena are ignored altogether or even worse, modeled incorrectly. Other areas of research that could encounter similar issues also showed a variety of approaches that showed limitations in their applicability to the problem at hand.

This led to the development of a new formulation based on the coupling of models based on molecular kinetics and commonly used advection-diffusion models. The approach not only quantifies the impact of the transition flow regime but also reproduces the pressure dependence of the Klinkenberg parameter as well as its physical origin[1], not accurately considered nor completely explained until now.

It is worth noting that this proposed formulation may have impacts beyond that of natural gas flow in tight sands. Other areas that could be benefit from a more comprehensive understanding of the gas transport through tight porous systems are: heterogeneous catalysis and adsorption problems[2] in situ remediation techniques for removal of Volatile Organic Compound (VOCs) and Non-Aqueous Phase Liquid (NAPLs)[3,4], prediction of gas transport into surrounding media from the disposal of hazardous waste sites[5], among others.

5 EXPERIMENTAL

The scope of work covered by this grant does not contemplate any experimental laboratory work. All the work performed is theoretical and based on analytical models of the fluid flow phenomenon. However, we do use readily available experimental data to validate the models we are developing [6] [7].

6 RESULTS AND DISCUSSION

The influence of microscopic flow mechanisms on gas production parameters in tight sand reservoirs can help identify possible relationships and dependencies between macroscopic reservoir parameters and well performance. Subsequently, it can be used in the development of rigorous, macroscopic equations that more accurately describe the fluid flow behavior in tight gas reservoirs and allow operators to better assess well completion strategies, predict well performance, and avoid tight gas well production problems, such as unexpected associated water production or varying gas production.

As part of the tasks that are defined in the Project Objectives, a review of field experiences, lab experiments, past flow modeling and reservoir simulators for the description of flow in tight gas sands was completed (Activity I.1). This review confirmed that many discrepancies exist between the different models that are used to represent the flow in tight porous media. Before embarking on a detailed study of the different effects of microscopic mechanisms, a brief survey and comparison of the different effects was done (Activity II.1). A system of macroscopic transport equations that model two-phase (gas-water) flow through tight porous media was developed. The porous medium was modeled using a dual-porosity and dual-permeability approach. Phenomena such as, Knudsen diffusion, electro-kinetic effects, diffusion of dissolved gas in water and water vaporization were captured in the proposed formulation. The transport equations were discretized in a 2D finite differences scheme and solved numerically. Results are being developed to compare with other single and multi-mechanistic approaches commonly used for tight sand reservoirs. In the coming year we will analyze the model predictions for various reservoir properties, initial conditions and exploitation strategies. Preliminary results indicate differences in the predicted gas production from the models considered and the common underestimation when using a single-mechanistic approach.

As mentioned before, for cases for when the pore size is so small that this dimension is comparable to the mean free path of molecules, the governing equations of fluid motion are different than those that govern flow in conventional porous media [8] [9] which are the basis for traditional reservoir simulators.

Common tight sands have shown to be dual porosity rocks where a fraction of the void space is conformed by secondary pores and the other by the flow paths among these pores which consist of intergranular slots. Other tight sands have been observed as a pore structure, where the void space consist of primary intergranular porosity propped open by contact points between individual rounded quartz sand grains [10 11].

Reports confirm most common tight sands have slit-like or sheet-like pore types as a the primary porosity [12 13 14 15]. Pores morphology analyses in several cases have been based on petrography and on the behavior of parameter like the Klinkenberg factor. Thin sections have shown that a network of polyhedral sheets is strongly related to pore size distribution for most of tight sands of potential commercial interest and this structure controls the permeability to gases for this low permeability media[14].

The literature widely reports very small characteristic sized for the flow path openings in tight sands. Some calculated widths have been in the range of 0.03 to 0.27 μm[13] which include other realm of sizes reported [12 16]. Other estimations for sands with permeabilities below 1 mD showed thicknesses from 0.2 to 4 μm[14].

Surface areas measured by nitrogen adsorption are typically about 200 times greater than sheet-type pore areas existent which is reported as the controller of permeability[14]. According to that, the surface area of the polyhedral structure is only a small fraction of the total surface area of the system. The surface area appears to be dominated by the named matrix which consist of significantly fine particles, such as clays, cherts and others micro-porous minerals.

Some have evaluated porosity on the basis of pore quality and model of occurrence. Pore quality was defined as a value based on the degree of porosity occlusion, going from 0 (a solid mineral grain) to 1 (a completely empty pore). According to this definition, a rock with high quality porosity should have a pore quality near 1 and rocks with several occlusions of pore spaces (fine structured minerals as clays, cherts) will have pore quality closer to 0.25. The study showed a range in pore quality between 0.26 and 0.45, which translates in an abundance of clays and other forms of microporosity [17]. Bossier sands have effective porosities that vary from 1 % to 17 %, while permeability rages from 0.001 to 1 mD, but permeabilities lower than 0.001 mD are associated to non-reservoir and seal rocks [18].

Despite this evidence, there is an important group of publications that reflect the use of conventional reservoir simulators for the modeling of fluid flow in tight sand reservoirs[19 20 21].

A commonly used approach is based on the use of "dual porosities", usually when extensive fracture networks and/or cavities are found as part of the porous media. These can be grouped according to the way fractures are treated[22]:

- Fractures are modeled as high permeability zones with the reservoir model.
- Fractures and matrix are modeled separately and coupled though a mass and momentum transfer function.
- Fractures are modeled by modifying the transmissibility between reservoir zones that contain them.

The first treatment is the "traditional" approach. It is recommened when the fluid flow in the rock matrix and in the fractures can be modeled with the same set of equations.

Discrete network models are more adequate than Dual porosity models when fluid flow towards production wells is dominated by flow through fractures[23]. In fact, concepts such as skin factor and drainage radius lose physical meaning when flow is mainly through fractures.

A comparison between single porosity models and fractures reservoir models[23] was made by using a discrete fractured network through which fluid flows towards production wells. When compared to a conventional approach to describe the flow from the matrix to the fractures, significant flow differences are observed.

Significant strides were made more than two decades ago in the simulation of low permeability reservoirs. Many authors focused on a physical and mathematical description of these peculiar systems in order to explain the unexpected results that were being reported [24] [25] [26].

The most common approach was to modify certain aspects of conventional reservoir simulators. For example, BOAST (Black Oil Applied Simulation Tool) was modified[27] as to how it calculated the gas formation (release) factor and the properties of the gas by using an updated equation of state (Peng-Robinson). The gas could be in solution in the water and there was no oil present. The dependence of permeability with pressure was introduced though an empirical equation developed by McKee. The effective permeability of each block was estimated by performing a weighted average of the width of the fracture and the width of the rock matrix.

This modified simulator was used in many evaluations and sensibility studies of flow in reservoirs[28]. The use of Corey's correlation to estimate relative permeabilities led to underestimations of gas production. In order to correct this, permeabilities were obtained by performing history matches from actual production data (higher permeabilities were necessary). They report that from the sensibility studies performed, modifications in the interfacial forces between the gas, the water and the porous media had the greatest impact.

Many tight reservoirs are naturally fractured. A simulator was developed to predict and study the behavior of these reservoirs[29]. The simulation tool was used to study the effects of fracture concentration, capillary pressure in the fractures and lenticularity on the fluid flow[30]. The simulator assumes that the fracture plane coincides with two of the three Cartesian axes. The model treats a fractured cellblock as being naturally fractured along any two of the principal axes. Traditional treatment (Darcy flow) of the fluid flow equations was performed for both water and gas. The authors use the effective permeability and average porosity concepts for each cell block. The effective permeability was calculated in such a way that it was dependent of the cellblock dimension.

Following along the same line of thought, others focused their efforts on obtaining the permeability tensor by creating a "realistic" fracture network model from outcrops and core data and incorporating this network into the reservoir simulator [31 32 33 34]. It should be noted that the interaction between the fracture network and the rock matrix is poorly understood at the reservoir length scale. The traditional uncertainty surrounding the geometry of fractures and their dynamic behavior can now be added to the uncertainty surrounding the appropriateness of the fluid flow equations that are used.

The dependence of permeability with stress is such that most of reduction in permeability occurs in sandstones with the lowest values of porosity and permeability. The rate of permeability decline with increasing stress is known to be highly variable and as a consequence reservoir exploitation parameters such as abandonment pressure are variable [12 35].

Implications for production (rate and total volume) of stress dependent permeability have been evaluated based on a reservoir simulator, which incorporates pore pressure dependent transmissibility[35]. The model is a 3D radial model that uses stress-dependent porosity and permeability data, and considers that the only mobile phase is gas. The overburden pressure is calculated assuming a lithostatic gradient of 1.0 psi/ft with a reservoir depth of 8000 ft.

The effect of the, usually large, amount of water pumped during hydraulic fracturing on well productivity is also poorly understood. The location of water in the formation is influenced by geo-mechanical effects, particularly by stress-dependent permeability. In order to investigate water blockage or formation damage a combined reservoir/geomechanics/fracturing model has been used[36]. This kind of model focuses on the modeling of the dynamic fracture evolution during pumping, stress dependent reservoir permeability during injection and production, and the stress dependent propped fracture conductivity.

An evaluation of the "dual" mechanisms of production has been studied[26]. However, our review unveiled several important limitations:

- The micro-pores are considered accessible only to gas, whereas the water primarily resides in the macro-pores. This seems to be a direct extrapolation or similar application of a model developed and used to model methane flow through coal beds. However, the distribution of fluids is highly different in tight sands. In tight sands, water should be the phase in contact with the pore surface and should be found in the pore throats and corners while the gas should be found in the pore cavities, independent of pore size. This is captured in a reservoir simulator with appropriate relative permeability curves and capillary pressure.
- It is said that when a pressure gradient is imposed, the thermodynamic equilibrium is distorted between the gas that is in solution in the water ant the gas that is present in the micro-pores, creating local concentration gradients. Following that line of thought, gas should be driven into the macro-pores by diffusion. However, if water is the wetting phase, with gas in the small pores and water in the large pores, the system is not in thermodynamic equilibrium, even before of the imposed pressure gradient, since capillary pressure would favor the flow of the gas towards the large pores.
- The equations capture the slippage effect through the diffusive mechanism. However, arbitrary diffusion coefficients are used for predictions. The Knudsen diffusion is not clearly involved, but ordinary diffusion seem to be used instead of it. At least an insufficient understanding of this issue is revealed from the publication. Both diffusive mechanisms are physically different and their macroscopic manifestation can not be mixed.

Given the above mentioned deficiencies, we opted to develop a tool that would overcome them. We modeled the porous medium using a dual-porosity and dual-permeability approach. Phenomena such as, Knudsen diffusion, electro-kinetic effects, diffusion of dissolved gas in water and water vaporization were captured in the proposed formulation.

The electrokinetic effects are captured via a correlation[12] obtained between the water relative permeability and the porous media permeability to liquids (it is considered also as gas permeability when the pressure tends to infinity). Knudsen diffusion is introduced through the Klinkenberg equation and a correlation that relates the slippage parameter and the resulting Klinkenberg permeability[12] is used. The slippage parameter is related to Knudsen diffusion through molecular kinetic models. The pressure dependence of the Klinkenberg slippage parameter is being studied and results will be introduced into the simulator.

Another phenomenon that is incorporated is the need to correct the volumetric factor of a liquid when measured outside the porous media, as is usual in a PVT lab, and when confined in one by the capillary pressure effect.

We have been able to observe differences in the predicted gas production from the models considered and an underestimation when using a single-mechanistic approach. The implementation allows for the consideration of combinations of the effects to determine not only their superposition but also their possible non-linear interactions.

The equations used in the model are not completely compatible with some molecular kinetics model such as the Dusty Gas Model. We studied the relationship between the Klinkenberg slippage parameter and the Knudsen diffusion and determined that neither the Dusty Gas Model nor the Advection Diffusion Model were capable of capturing a pressure dependence for Klinkenberg's slippage parameter. This dependence has been observed to be more relevant as the permeability of samples is reduced. This is a clear indication that the slippage phenomenon needs to be understood in more detail before any additional progress can be made.

The macroscopic modeling of slippage phenomena is being carried out. The Klinkenberg parameter, b, which is supposed to represent the slippage phenomenon, has been traditionally accepted as a constant independent of pressure. However, since the original work of Klinkenberg it has been observed to have pressure dependence. We have obtained an analytical dependence of the parameter b with the Knudsen number, which is capable of reproducing the experimental behavior observed by Klinkenberg in his original work and other experimental works reported. The new approach reveals that under certain conditions (porous media properties, fluid parameters and rock-fluid interactions) if one overlooks the pressure dependence of the Klinkenberg parameter b, this would produce a greatly inaccurate predictions of flow. This error becomes even greater when pore size is reduced.

7 CONCLUSION

Much work is still necessary to develop, and have readily available, more reliable reservoir simulators that can be used to model tight sand reservoirs. The main objective of this research is to on the impact of microscopic fluid flow dynamics on macroscopic behavior. With this in mind we are first developing a better understanding of the pressure dependence of pore scale slippage flow phenomena. We have identified that this improved understanding is needed in order to more accurately predict reservoir performance in tight sand reservoirs.

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